Attachment B

1. QF Payment @ $80/MWh
2. Includes Imputed RRB Credits

Southern California Edison Company
Calculation of California Procurement Adjustment
(As Set Forth in ABX1)
(Unless Denoted Otherwise, Amounts are in Thousands)

Line		*2001 Estimate*											
No.	Component	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
1.	Total Delivered Sales (Metered GWh)	6,290	6,715	6,419	6,722	7,029	7,491	8,275	7,573	7,619	6,663	6,665	77,461
2.	Generation Rate As of 1-05-01 ($/MWh)	56.85	56.85	56.85	56.85	63.46	73.37	73.37	73.37	66.76	56.85	56.85	63.40
3.	Emergency Procurement Surcharge ($/MWh)	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
4.	Generation Rate + EPS ($/MWh)	66.85	66.85	66.85	66.85	73.46	83.37	83.37	83.37	76.76	66.85	66.85	73.40
5.	Gross Generation Revenue	(420,491)	(448,867)	(429,135)	(449,338)	(516,369)	(624,491)	(689,869)	(631,351)	(584,874)	(445,435)	(445,551)	(5,685,772)
Adjustments:													
6.	Franchise Fees and Uncollectibles	4,717	5,035	4,814	5,040	5,792	7,005	7,738	7,082	6,561	4,996	4,998	63,777
7.	Direct Access Credit	39,083	41,720	39,886	41,764	47,994	58,044	64,120	58,681	54,362	41,401	41,412	528,467
8.	RMR	3,296	3,296	3,296	3,296	3,296	3,296	3,296	3,296	3,296	3,296	3,296	36,255
9.	Restructuring Implementation	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	30,805
10.	Other Authorized Costs/Credits	7,236	7,205	7,174	7,143	7,112	7,081	7,050	7,019	6,988	6,957	6,926	77,891
11.	Imputed 10% Rate Reduction	(27,814)	(31,663)	(27,926)	(29,852)	(32,524)	(36,685)	(42,554)	(36,322)	(33,843)	(31,268)	(31,130)	(361,582)
12.	Imputed TTA	(22,637)	(26,571)	(21,369)	(24,313)	(29,005)	(29,254)	(37,448)	(30,544)	(26,960)	(23,893)	(22,897)	(294,891)
13.	**Generation-Related Component**	**(413,809)**	**(447,044)**	**(420,460)**	**(443,458)**	**(510,904)**	**(612,204)**	**(684,866)**	**(619,339)**	**(571,671)**	**(441,145)**	**(440,146)**	**(5,605,048)**
14.	Generation-Related Rate ($/MWh)	72.61	73.49	72.29	72.82	80.22	90.21	91.35	90.27	82.81	73.08	72.89	79.87
Less:													
15.	A. SCE Owned Generation Rev Rqmt:												
16.	Capital Related	24,612	24,612	24,612	24,612	24,612	24,610	24,608	24,608	24,605	24,603	24,605	270,694
17.	SONGS ICIP	32,282	49,393	47,798	49,393	47,798	49,393	49,393	47,798	49,393	47,798	49,393	519,829
18.	Other On-Going (PV, Coal, and Hydro)	32,546	33,210	28,083	32,442	32,818	34,851	35,879	34,629	33,767	35,808	35,996	370,027
19.	Subtotal	89,439	107,214	100,492	106,446	105,228	108,853	109,879	107,035	107,764	108,208	109,993	1,160,551
20.	B. QF Payments:												
21.	QF Energy and Capacity Costs ($80)	174,400	158,240	176,080	171,600	179,440	174,640	178,480	176,560	168,400	174,000	166,800	1,898,640
22.	QF Buyouts	3,587	6,712	20,395	3,587	6,712	20,395	3,587	6,712	20,395	3,587	7,024	102,693
23.	Shareholder Incentives	-	-	-	-	-	-	-	-	-	-	-	-
24.	Scheduling, Dispatch & Admin	70	70	70	70	70	70	70	70	70	70	70	770
25.	Subtotal	178,057	165,022	196,545	175,257	186,222	195,105	182,137	183,342	188,865	177,657	173,894	2,002,103
26.	C. Bilateral Contract Costs:												
27.	Interutility Net Contract Costs	9,836	10,372	10,712	9,239	10,420	11,760	11,775	12,082	12,433	10,352	10,568	119,549
28.	Interutility Buyouts	-	-	-	-	-	-	-	-	-	-	-	-
29.	Scheduling, Dispatch & Admin	262	262	262	262	262	262	262	262	262	262	262	2,877
30.	BFM Contracts Costs	-	-	-	-	-	-	-	-	-	-	-	-
31.	Bilateral Contract Costs	11,752	13,032	12,557	12,984	12,605	17,679	17,775	17,099	15,624	14,957	15,336	161,400
32.	Subtotal	21,850	23,666	23,531	22,485	23,287	29,701	29,812	29,443	28,319	25,571	26,166	283,826
33.	D. Ancillary Services (including GMC)	74,960	82,590	81,755	89,206	90,159	103,498	107,246	96,762	91,246	79,300	81,102	977,824
34.	Subtotal (A + B + C + D)	364,305	378,492	402,323	393,393	404,895	437,157	429,073	416,581	416,194	390,735	391,155	4,424,304
35.	Current Month (Over)/UnderCollection	(49,504)	(68,552)	(18,137)	(50,065)	(106,009)	(175,047)	(255,792)	(202,758)	(155,478)	(50,410)	(48,992)	(1,180,744)
36.	Accumulated UnderCollections	-	-	-	-	-	-	-	-	-	-	-	-
37.	Interest (6.5% Short-Term)	-	-	-	-	-	-	-	-	-	-	-	-
38.	**California Procurement Adjustment**	**(49,504)**	**(68,552)**	**(18,137)**	**(50,065)**	**(106,009)**	**(175,047)**	**(255,792)**	**(202,758)**	**(155,478)**	**(50,410)**	**(48,992)**	**(1,180,744)**

Est. Net Short GWh (Feb through Dec)	21,171
CPA/Est. Net Short (GWh)	$55.77

NOTE: All assumptions are listed on the attached sheet.

Attachment C

Pacific Gas and Electric Company
Calculation of California Procurement Adjustment
(As Set Forth in AB1X)
($000s)

Scenario 1: QF at $80/MWh

Line No.	Component	*Estimated* February	March	April	May	June	July	August	September	October	November	December	Total
1.	Sales (Metered)	6,454	6,538	6,354	6,420	6,846	7,272	7,572	7,670	6,936	6,405	6,770	75,238
2.	Generation Rate As of 1-05-01 /1	50.03	48.70	47.80	53.85	60.51	60.51	60.42	60.40	60.92	54.22	49.58	55.44
3.	Emergency Procurement Surcharge	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75
4.	Generation Rate + EPS	59.78	58.45	57.55	63.60	70.26	70.26	70.17	70.15	70.67	63.97	59.33	65.19
5.	Gross Generation Revenue	(385,828)	(382,130)	(365,689)	(408,329)	(480,986)	(510,900)	(531,344)	(538,068)	(490,191)	(409,732)	(401,668)	(4,904,865)
Adjustments:													
6.	Franchise Fees and Uncollectibles	3,731	3,695	3,536	3,948	4,651	4,940	5,138	5,203	4,740	3,962	3,884	47,425
7.	Direct Access Credit /2	36,266	35,919	34,372	38,382	45,210	48,022	49,945	50,580	46,078	38,514	37,754	461,042
8.	RMR /3	0	0	0	0	0	0	0	0	0	0	0	0
9.	Restructuring Implementation	0	0	0	0	0	0	0	0	0	0	0	0
10.	Remaining Transition Costs/Credits	9,366	10,447	10,724	25,312	30,903	16,099	13,197	14,298	14,403	15,011	2,821	162,581
11.	Imputed 10% Rate Reduction	(36,309)	(34,717)	(32,148)	(33,063)	(37,508)	(40,553)	(42,451)	(42,315)	(38,664)	(34,703)	0	(372,431)
12.	Imputed FTA	(32,575)	(31,349)	(29,259)	(28,462)	(30,511)	(32,896)	(34,378)	(34,246)	(31,443)	(29,875)	0	(314,995)
13.	**Generation-Related Component**	**(405,349)**	**(398,135)**	**(378,464)**	**(402,213)**	**(468,242)**	**(515,288)**	**(539,893)**	**(544,549)**	**(495,077)**	**(416,823)**	**(357,209)**	**(4,921,243)**
Less:													
14.	A. PG&E Owned Generation Rev Rqmt:												
15.	A1. Hydro												
16.	2001 Revenue Requirement /4	33,351	33,386	33,351	33,295	33,045	33,661	33,352	33,067	33,021	33,021	33,021	365,571
17.	A2. Fossil												
18.	2001 Revenue Requirement /4	18,198	30,354	15,734	16,827	19,020	20,161	19,900	19,685	18,296	17,745	17,244	213,165
19.	A3. Nuclear												
20.	Diablo ICIP	48,678	53,862	50,332	27,049	50,404	53,862	53,862	52,134	53,934	52,134	53,862	550,115
21.	CCFT Credit	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(3,783)	(41,613)
22.	Subtotal	44,895	50,079	46,549	23,266	46,621	50,079	50,079	48,351	50,151	48,351	50,079	508,502
23.	Subtotal (A1 + A2 + A3)	96,443	113,819	95,634	73,389	98,686	103,901	103,331	101,104	101,469	99,118	100,345	1,087,239
24.	B. QF Payments												
25.	QF Expenses	124,218	128,629	127,371	144,072	152,047	155,793	153,613	144,032	140,423	128,515	141,331	1,540,043
26.	QF Admin & Legal Costs	759	759	759	759	759	759	759	759	759	759	759	8,349
27.	Subtotal	124,977	129,388	128,130	144,831	152,806	156,552	154,372	144,791	141,182	129,274	142,090	1,548,392
28.	C. Bilateral Contract Costs:												
29.	Irrigation District Contracts and Other /5	(12,202)	(10,681)	(7,140)	1,112	7,360	280	(5,639)	(9,151)	(10,572)	(4,272)	1,544	(49,362)
30.	BFM Contracts Costs /6	0	0	0	0	0	0	0	0	0	0	0	0
31.	Bilateral Contract Costs	8,904	8,349	6,503	6,763	6,763	23,129	23,753	22,321	22,349	21,335	21,829	171,998
32.	Subtotal	(3,298)	(2,332)	(637)	7,875	14,123	23,409	18,114	13,170	11,777	17,063	23,373	122,636
33.	D. ISO Ancillary Services and Related Charges /7	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	220,000
34.	Subtotal (A + B + C + D)	238,121	260,876	243,127	246,095	285,614	303,861	295,817	279,065	274,427	265,455	285,808	2,978,267
35.	Current Month (Over)/UnderCollection	(167,228)	(137,259)	(135,337)	(156,118)	(182,628)	(211,427)	(244,076)	(265,484)	(220,650)	(151,369)	(71,401)	(1,942,976)
36.	Accumulated UnderCollections	0	0	0	0	0	0	0	0	0	0	0	0
37.	Interest (6.5% Short-Term) if Undercollection	0	0	0	0	0	0	0	0	0	0	0	0
38.	**California Procurement Adjustment**	**(167,228)**	**(137,259)**	**(135,337)**	**(156,118)**	**(182,628)**	**(211,427)**	**(244,076)**	**(265,484)**	**(220,650)**	**(151,369)**	**(71,401)**	**(1,942,976)**

Net Short GWh (Feb through Dec)	32,927
Contribution to Net Short ($/MWh)	$59.01

Attachment D

San Diego Gas & Electric Company
Calculation of California Procurement Adjustment for Uncapped Customers
(As Set Forth in ABX1)

Line No.	Component ($000)	*2002 Estimate*												
		January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
1.	Delivered Sales (GWH)	355	353	353	361	369	398	425	423	448	412	390	374	4,662
2.	Projected Uncapped Generation Rate ($/MWH)	87.19	74.83	73.12	73.03	73.32	83.98	98.43	120.70	110.25	91.94	72.07	65.91	74.83
3.	Gross Generation Revenue	(30,995)	(26,444)	(25,831)	(26,330)	(27,032)	(33,457)	(41,863)	(51,005)	(49,378)	(37,891)	(28,095)	(24,662)	(402,982)
Adjustments:														
4.	Franchise Fees and Uncollectibles	255	240	238	243	249	282	319	345	352	301	262	244	3,330
5.	**Generation-Related Component**	**(30,740)**	**(26,204)**	**(25,593)**	**(26,087)**	**(26,783)**	**(33,175)**	**(41,543)**	**(50,660)**	**(49,026)**	**(37,589)**	**(27,833)**	**(24,418)**	**(399,652)**
Less:														
6.	A. SDG&E Owned Generation Rev Rqmt:													
7.	SONGS ICIP	3,635	3,443	3,880	3,886	3,730	1,991	3,468	3,947	3,754	2,330	3,745	3,812	41,620
8.	B. QF Payments:													
9.	QF Energy and Capacity Costs	2,297	2,409	2,451	2,537	3,917	3,969	3,853	3,738	3,673	2,571	2,571	2,409	36,396
10.	C. Bilateral Contract Costs:													
11.	Interutility Net Contract Costs (PNM & PGE)	1,032	1,065	1,102	1,134	1,068	1,090	1,157	1,122	1,097	1,157	1,151	1,083	13,259
12.	Bilateral Contracts	1,274	1,209	1,359	1,366	1,450	1,420	1,426	1,389	1,309	1,432	1,379	1,330	16,344
13.	Subtotal	2,306	2,275	2,461	2,501	2,518	2,510	2,583	2,511	2,406	2,589	2,530	2,413	29,603
14.	D. Ancillary Services (including GMC)	2,222	1,969	2,181	1,986	2,161	2,872	3,784	4,686	3,525	2,377	1,972	1,999	31,734
15.	Subtotal (A + B + C + D)	10,460.90	10,095.27	10,973.17	10,909.83	12,326.57	11,341.96	13,687.60	14,881.79	13,358.85	9,866.62	10,817.40	10,632.71	139,353
16.	Current Month (Over)/UnderCollection	(20,279)	(16,109)	(14,620)	(15,178)	(14,456)	(21,833)	(27,856)	(35,778)	(35,667)	(27,723)	(17,016)	(13,785)	(260,300)
17.	Accumulated UnderCollections	(20,279)	(16,109)	(14,620)	(15,178)	(14,456)	(21,833)	(27,856)	(35,778)	(35,667)	(27,723)	(17,016)	(13,785)	(260,300)
18.	Interest (6.5% Short-Term)	-	-	-	-	-	-	-	-	-	-	-	-	-
19.	**California Procurement Adjustment**	**(20,279)**	**(16,109)**	**(14,620)**	**(15,178)**	**(14,456)**	**(21,833)**	**(27,856)**	**(35,778)**	**(35,667)**	**(27,723)**	**(17,016)**	**(13,785)**	**(260,300)**

Est. Net Short GWH (Feb. through Dec.)	2,986
CPA / Est. Net Short ($/MWH)	87.18

FOOTNOTES 1/ Represents Utility Bundled Sales. The approximate split between AB265 Capped and Non-AB265 Customers is 70 / 30. Direct Access is not included because the CPUC has not yet approved cap plementation for them.

2/ The California Procurement Adjustment amount calculated above reflects the monthly amount available to the DWR for procuring power for utility customers, including the cost of imbalance energy and imbalance penalties.

Attachment E - Revised
Based on Utility Provided Scenarios, 12 month Projections for 2001

	A	B	C	D	E	F	G	H	I
	Total Generation - Related Rate (¢/kWh)	Sales Reported in Utilities' ABX1 Data (GWh)	Bundled Service Sales (GWh)	Gross Gen. - Related Revs Reported in Utilities' ABX1 Data ($000s)	Gen. - Related Revenues Based on Bundled Service Sales ($000s)	Utility Related Costs ($000s)	Utility Related Costs less CSI and A&G ($000s)	CPA Revenues ($000s)	CPA Rate (¢/kWh)
	A=D/B/10				E=A*C*10			H=E-G	I=H/C
PG&E	6.471	82,008	74,299	$5,306,533	$4,807,719	$3,090,494	$3,014,546	$1,793,173	2.413
SCE	7.277	84,400	76,466	$6,141,557	$5,564,251	$4,743,502	$4,707,821	$856,430	1.120
SDGE Capped	6.500	11,163	11,163	$725,570	$725,570	$422,279	$422,279	$303,291	2.717
SDGE Uncapped	12.539	4,606	4,606	$577,565	$577,565	$174,636	$174,636	$402,929	8.748
Totals				$12,751,225	$11,675,105	$8,430,911	$8,319,282	$3,355,823	

Notes

Column A: Calculated based on gross generation-related revenues shown in column D and sales shown in column B.

Column B: Based on Utilities' sales data provided in ABX1 implementation worksheets emailed to parties in A.00-11-038, et.al, on 2-9-01.
PG&E: Scenario 1: (QFs at $80/MWh); Total metered sales for 2/'01 thru 12/'01 (75,238 GWh), plus 12/'01 sales (6,770 GWh) for 12th month.
SCE: Scenario with QFs at $80/MWh: Total metered sales for 2/'01 thru 12/'01 (77,461 GWh), plus 1/'02 sales (6,939 GWh) for 12th mo.
SDG&E: Total delivered sales for 2/'01 thru 12/'01 (10,192 GWH for capped; 4,251 GWh for uncapped), plus 1/'02 sales (971 GWh for capped; 355 GWh for uncapped) for 12th mo.

Column C: PG&E & SCE: Column B x 0.906 to remove sales to direct access customers.

Column D: Based on Utilities' sales data provided in ABX1 implementation worksheets emailed to parties in A.00-11-038, et.al, on 2-9-01.
PG&E: Scenario 1: (QFs at $80/MWh); Gross generation revenue for 2/'01 thru 12/'01 ($4,904,865), plus 12/'01 revenue ($401,668) for 12th month.
SCE: Scenario with QFs at $80/MWh: Gross generation revenue for 2/'01 thru 12/'01 ($5,685,772), plus 1/'02 revenue ($495,336) for 12th mo. less RMR ($36,255 for Feb. '01 thru Dec. '02, plus $3,296 for Jan. '02).
SDG&E: Total delivered sales for 2/'01 thru 12/'01 ($662,458 for capped; $546,470 for uncapped), plus 1/'02 revenues ($63,112 for capped; $30,995 for uncapped) for 12th mo.

Column E: Calculated based on total generation rate shown in Column A and bundled service sales shown in column C.

Column F: Based on Utilities' sales data provided in ABX1 implementation worksheets emailed to parties in A.00-11-038, et.al, on 2-9-01.
PG&E: Scenario 1: (QFs at $80/MWh); Costs for PG&E-owned gen., QFs, Bilaterals, and Ancillary Services for 2/'01 thru 12/'01 ($2,978,267), plus 12/'01 costs ($285,808) for 12th month, minus $173,581 to reflect actual nuclear operating costs.
SCE: Scenario with QFs at $80/MWh: Costs for SCE-owned gen., QFs, Bilaterals, and Ancillary Services for 2/'01 thru 12/'01 ($4,424,304), plus 1/'02 costs ($374,598) for 12th mo, minus $55,400 to reflect actual SONGS operating costs.
SDG&E: Cost for SDG&E-owned gen., QFs, Bilaterals, and Ancillary Services, excluding PECA amoritzation for 2/'01 thru 12/'01 ($403,402 for capped; $168,330 for uncapped) plus 1/'02 costs ($28,572 for capped; $10,461 for capped) for 12th mo, minus $13,850 ($9,695 for capped, $4,155 for uncapped) to reflect actual nuclear operating costs.

Column G: Column F less Customer Service and Information, and A&G costs identified in utilities data supporting ABX1 implementation worksheets.
PG&E: Column F minus $75,948; SCE: Column F minus $35,681.